Appendix #18

M. Kunce, S. Gerking, W. Morgan, R. Maddux. "State Taxation, Exploration and Production in the U.S. Oil Industry," January 22, 2002

STATE TAXATION, EXPLORATION, AND PRODUCTION IN THE U.S. OIL INDUSTRY*

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January 22, 2002

* This research was partially supported by an appropriation from the Wyoming Legislature (1999 Wyoming Session Laws, Chapter 168, Section 3). However, this paper may or may not reflect the views of public officials in the State. Gerking acknowledges the hospitality of CentER, Tilburg University, where portions of this paper were completed, as well as support from visiting grant B46-386 from the Netherlands Organization for Scientific Research (NWO). Maddux acknowledges the support of a student EPSCoR research fellowship from the University of Wyoming. We thank Laura Marsiliani and John Livernois for a number of constructive suggestions on earlier drafts.

STATE TAXATION, EXPLORATION, AND PRODUCTION
IN THE U.S. OIL INDUSTRY

Abstract

How do firms in nonrenewable resource industries respond to changes in state taxes? This paper employs state-specific estimates of Pindyck's (1978) widely cited model of natural resource supply to simulate effects of changes in state production (severance) tax policy on the timing of exploration and output by firms in the U.S. oil industry. The framework developed can be applied to any of 15 states that produce significant quantities of oil, and allows for interactions between taxes levied by different levels of government. Results of this study suggest that oil production is highly inelastic with respect to changes in production taxes. A production tax rate increase is shown to decrease early period exploration effort, result in little change in reserve additions and future production, and substantially increase discounted tax revenue. Policy implications of this outcome suggest that state officials may consider raising production tax rates as a way to increase revenue while risking little in the way of loss to future oil field activity.

1. Introduction

How do firms in nonrenewable resource industries respond to changes in state taxes? It may be tempting to look for answers to this question in the empirical literature on effects of state taxation (see, for example, Bartik 1985, Helms 1985, Papke 1991, 1994, and Holmes 1998). These papers, however, focus on firms with geographically mobile capital, a perspective that is not particularly relevant when looking at the behavior of firms extracting nonrenewable natural resources. Such firms cannot change location because they are tied to a geographically immobile reserve base that makes up a key component of their capital stock. On the other hand, extractive firms can alter the level and timing of their activities when state taxes and other public policies change. Yet, little empirical evidence is available about the extent to which they do this despite longstanding concern in public economics about distortions that can arise when taxes on resource-based industries are levied at the sub-national level (see Inman and Rubinfeld 1996) and despite the heavy reliance on taxation of oil, gas, and/or coal production in many states to fund public services.

This paper makes use of a standard theoretical model of natural resource supply (Pindyck 1978) to simulate effects of changes in state production (severance) taxes on the level and timing of exploration and production by firms in the oil industry. The simulation model developed represents an attempt to improve on previous econometric and/or simulation studies of relationships between taxation and natural resource exploration and production and can be applied to any of 15 states that produce significant quantities of oil. For example, Deacon, DeCanio, Frech, and Johnson (1990) and Moroney (1997) focus only on one state (California and Texas, respectively), and estimate econometric equations that may not be consistent with a dynamic profit-maximizing framework. Pesaran (1990) estimates an econometric model of offshore oil production in the UK that can be better justified theoretically, but does not consider the role of taxes and estimates of the shadow price of oil in the ground are not always positive. Favero (1992) adds taxes to Pesaran's analysis, but again, estimates of the shadow price of oil in the ground are sometimes negative, suggesting that the model overstates the impact of taxation on profit. Simulation studies conducted by Yucel (1989) and Deacon (1993) examine effects of various types of tax changes on exploration and production but do not consider interactions between tax bases claimed by different levels of government, as well as possible interstate differences in exploration and extraction costs. Also, these studies are aimed mainly at assessing the generality of theoretical results obtained in more limited settings (see, for example, Burness 1976, Conrad and Hool 1980, and Heaps 1985) rather than analyzing possible outcomes of changes in state tax policies. Severance taxes are analyzed here because they are the most important state tax faced by U.S. oil producers and because the choice of severance tax rates frequently is a highly contentious political issue in light of its implications for provision of public services, revenues needed from other types of state and local taxes, employment in the oil and related industries, and profits of oil producers. Results suggest that oil production is highly inelastic with respect to changes in these tax rates. Implications of this finding are developed in greater detail below.

2. The Simulation Model

This section shows how Pindyck's model of nonrenewable resource supply is applied to simulate effects of state production tax changes. The discussion begins with a brief overview of this model and then describes how it is implemented.

Model Overview

The model assumes that perfectly competitive producers maximize the discounted present value of future operating profits from the sale of resources. Because one such firm is chosen to represent the industry, the common pool problem and well-spacing regulations are not considered (see McDonald 1994 for discussion of these issues). The firm's problem is to take the future time path of output prices and taxes as given and then choose optimal time paths for exploration and production. This approach is common in many econometric/simulation studies of effects of changes in state tax policy and ignores the possibility that choices of tax bases and rates are endogenous (i.e., that governments consider the firm's objective function in choosing taxes that maximize community welfare). Also, the model defines exploration to include resource development, although the two activities clearly are not the same (Adelman 1990). The aim of exploration is to add to the reserve base, which as indicated in the introduction, is a form of geographically immobile capital.

The firm's maximization problem is

$$\max_{q,w} \ \Omega = \int_0^\infty [qp - C(q,R) - D(w) - \gamma R] e^{-rt} \, dt \tag{1}$$

subject to

$$\dot{R} = \dot{x} - q \tag{2}$$

$$\dot{x} = f(w, x) \tag{3}$$

$$q \geq 0, w \geq 0, R \geq 0, x \geq 0 \tag{4}$$

where a dot over a variable denotes a time rate of change, q denotes the quantity of oil extracted measured in barrels, p denotes the exogenous market price per barrel net of all taxes, $C(\cdot)$ denotes the total cost net of taxes of extracting the resource, which is assumed to depend on production (q) and reserve levels (R), $D(w)$ denotes total cost of exploration for additional reserves net of taxes, w denotes exploratory effort, γ denotes the net of tax constant effective property tax rate on reserves, r denotes the discount rate which represents the risk-free real rate of long-term borrowing, x denotes cumulative reserve additions (discoveries), $f(\cdot)$ denotes the production function for gross reserve additions ($\dot{x}$), and $\dot{R}$ denotes reserve additions net of production (q).[1] In this formulation, the net of tax price per barrel is related to the wellhead (pre-tax) price (p^*) according to $p = \alpha_p p^*$, where α_p is a tax policy parameter such that $0 < \alpha_p < 1$. Correspondingly, $C(q,R) = \alpha_c C^*(q,R)$ and $D(w) = \alpha_D D^*(w)$, where α_c and α_D also are tax policy parameters that lie on the unit interval. These tax policy parameters are discussed more fully below and in Appendix A, however, three aspects should be noted before proceeding further. First, in general, $\alpha_p < \alpha_c$ because production taxes and public land royalty rates, unlike corporate income tax rates, are applied to gross revenue rather than operating income. Second, α_D reflects, among other things the opportunity to expense the costs of drilling dry holes along with certain intangible drilling costs. Third, all parameters are treated as independent of γ (see endnote 1).

The Hamiltonian for this problem is

$$H = qpe^{-rt} - C(q,R)e^{-rt} - D(w)e^{-rt} - \gamma Re^{-rt} + \lambda_1[f(w,x) - q] + \lambda_2[f(w,x)]. \qquad (5)$$

Differentiating H with respect to R, q, x, and w yields

$$\dot{\lambda}_1 = (C_R + \gamma)e^{-rt} \tag{6}$$

$$pe^{-rt} - C_q e^{-rt} - \lambda_1 = 0 \tag{7}$$

$$\dot{\lambda}_2 = -f_x(\lambda_1 + \lambda_2) \tag{8}$$

$$-D_w e^{-rt} + f_w(\lambda_1 + \lambda_2) = 0, \tag{9}$$

where letter subscripts denote partial derivatives. The shadow price λ_1 reflects the positive change in the present value of future profits from an additional unit of reserves. In equation (6), $\dot{\lambda}_1 < 0$ because $C_R < 0$ and γ is sufficiently small. The shadow price of cumulative reserve additions, λ_2, is expected to be negative (and small relative to λ_1) for oil because current reserve discoveries will increase the amount of exploration needed in the future. The evolution of λ_2 is increasing because $f_x < 0$. From equation (8) and equation (9), the term $(\lambda_1 + \lambda_2)$ equals the discounted value of the marginal cost of adding another unit of reserves by exploration $[D_w / f_w]e^{-rt}$. Because $0 < \alpha_D < 1$, this net marginal cost is lower than in the pretax case. The solution to this problem is well known as it has been discussed in detail elsewhere (e.g., see Pindyck 1978, pp. 844-46). Nevertheless, certain features of the model are worth reviewing before considering the simulations reported in section 3.

Regarding production, equation (7) shows that the firm will decide to produce ($q > 0$) if the discounted after-tax wellhead price net of marginal extraction costs exceeds the present value of future profits from an additional unit of reserves (λ_1). If the firm decides to produce, then production occurs at a maximal rate subject to constraints imposed by reserve levels and geological and technological conditions. Additionally, the firm adds to its reserve base through exploratory effort (w) and reserve additions reduce extraction costs ($C_R < 0$). Thus, decisions about the optimal amount of exploratory effort balance the net-of-tax marginal cost of adding a unit of reserves against increases in net-of-tax profits (explicitly λ_2). Thus, in this model, a severance tax increase can affect production in two ways. First, it can limit current incentives to explore. Reduced current exploration will limit future reserve additions thereby increasing extraction costs, which reduces future profits and production. Second, holding exploration effort constant, a severance tax increase can cause production to cease if the condition for positive output discussed above no longer is met. Notice again, however, that if it pays to produce both before and after the tax change, the level of production is left unchanged (apart from exploration effects).

Model Implementation

Effects of severance tax changes are studied empirically by obtaining state-specific estimates of equations for exploration costs (D^*), production of reserve additions (f), and extraction costs (C^*) and for tax parameters α_p, α_c, α_D, and γ and then inserting the results into the model described above. Because the dynamic equations of the model do not have closed form solutions, effects of tax changes in a particular state are obtained by simulation. Construction of the tax parameters is described first followed by a discussion of how equations for D^*, f, and C^* were estimated.

Tax Parameters. General considerations in developing estimates of the four tax policy parameters for major oil producing states are briefly outlined below and Appendix A shows how values for these parameters are obtained. Among major oil producing states, tax structures vary considerably and tax bases interact, particularly between the state and federal level. For example, among the eight states responsible for about 89% of U.S. oil production (Alaska, California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming), all states except California levy severance taxes against the value of production. These taxes dominate other forms of state/local taxation of oil in Alaska, Oklahoma, Texas, Wyoming, and Louisiana. Most states do not levy property taxes on the value of reserves in the ground (Texas and California do). Most states treat royalty payments (computed as a percentage of gross value of production) for production on public land as deductible items in computing severance tax liabilities (Louisiana does not). Public land royalties are prominent in Alaska, New Mexico, and Wyoming due to the large shares of publicly owned land. Most states levy a corporate income tax that applies to oil operators (Wyoming and Texas do not). Also, states have granted innumerable exemptions and credits (which differ by state) against various tax liabilities for special situations that may be encountered by operators. Within states, counties apply their own mill levies to compute property taxes on equipment at different rates. However, taxation of structures and equipment are usually less important than other sources of revenue and are ignored below.

Regarding federal taxes, all incorporated producers file federal corporate income tax returns that allow deductions for various types of operating costs and for state and local tax payments. Independent producers (those without downstream refining or retail interests) are permitted to take a percentage depletion allowance, while major producers are allowed only cost depletion, which is significantly less generous. Both major and independent incorporated producers can expense intangible drilling costs incurred on their federal corporate income tax returns. The fact that some smaller producers are not incorporated and may therefore face alternative state and federal tax treatment is ignored.

The myriad of state-specific special features described above creates considerable complexity in tracking tax law over time. Rather than itemize tax code details, effective tax rates are used to translate dynamic tax policy into a tractable form for the four tax policy parameters. Effective rates can be expressed as the ratio of taxes (or royalties) collected from a particular tax to the value of production. Thus, the calculation of specific effective tax rates fully accounts for exemptions, incentives, different tax bases, and frequent changes in tax law both at the state and federal level.

Marginal Cost of Reserve Additions. In this section, estimation of D_w and f_w are treated together because they are used to compute the before-tax marginal cost of reserve additions (D_w^* / f_w), a key relationship in the model described above. Drilling costs are assumed to be proportional to drilling effort as shown in equation (10)

$$D^*(w) = \phi w e^u \tag{10}$$

where ϕ is the parameter to be estimated and the disturbance term e^u is lognormally distributed with mean of unity and variance σ_u^2. This approach ensures that the objective function (see equation (1)) represents a perfectly competitive firm ($D_{ww} = 0$). The production function for gross reserve additions is specified as

$$f(w,x) = Aw^{\rho} e^{-\beta \cdot x} e^{v} \tag{11}$$

where A, ρ, and β are parameters to be estimated and the disturbance e^v is assumed lognormally distributed with mean of unity and variance σ_v^2. Equation (11) is similar to the equation describing the discovery process proposed by Uhler (1976) and later adopted by Pindyck (1978) and Pesaran (1990). The idea behind this equation is that the marginal product of exploration declines as reserve discoveries cumulate.

Estimation of equations (10) and (11) used annual data from the 15 U.S. states for which complete information on variables needed could be assembled for the period 1970-98.[2] These states accounted for 96.5% of total U.S. oil production over this time period. Drilling costs are measured by total real costs (both tangible and intangible) of each well completed, including dry holes.[3] Nominal cost values are converted to $1995 using the GDP deflator. Oil reserve additions are defined as extensions, new field discoveries and new reservoir discoveries in old fields. The total number of wells drilled for each state since 1859 (when the first oil well was drilled in Pennsylvania) is used as a proxy for x. Data sources, definitions, and sample means of all variables used in the analysis are presented in Table 1.

Equation (10) and equation (11) were estimated in natural logarithms. Both equations used an instrument for the number of wells drilled because w is an endogenous variable in the model presented in Section 2. The instrument was obtained from the predicted values from a regression of the number of wells drilled by state and year on cumulative drilling and the wellhead price as shown in Appendix A. Estimates of the drilling cost equation, equation (10), are obtained by regressing drilling cost per well on dummy variables for states and years. Coefficients of state and year dummies are jointly significant at the 1% level and the R^2 is 0.90. The idea behind using this approach is to obtain state- and time-specific estimates of ϕ. This parameter is expected to vary across states because of differences in geologic conditions, geographic remoteness of on-shore oil resources, and whether drilling occurs in off-shore coastal waters (note that most states in the data set are landlocked). Time varying factors common to all states may include technological advancement and macroeconomic cycles. State-specific estimates of ϕ test different from each other, except for Texas and Oklahoma, at the 5% level.

Estimates of equation (11), shown below in equation (12), allow for state-specific intercept terms (time-specific effects were jointly insignificant), common slope coefficients across states, and are corrected for first-order serial correlation (ρ=0.431). As shown in Table 1, *ADDED RESERVES* measures gross reserve additions by state and year and *CWELLS* denotes cumulative wells drilled by state and year since 1859. *PREDWELLS* is the predicted value of well numbers drilled by state and year from the regression reported in Appendix Table A.1.

$$\ln(ADDED\ RESERVES) = \ln A + \underset{(5.33)}{0.69} * \ln(PREDWELLS) - \underset{(-1.37)}{0.000006} * CWELLS\ . \qquad (12)$$
$$(t)$$

This equation, which has an $R^2 = 0.40$, shows that the marginal product of drilling (f_w) decreases with wells drilled as well as with cumulative drilling, although the coefficient of cumulative drilling is insignificant at conventional levels.[4] Also, equation (12) suggests that as w increases, the marginal product of drilling in finding new reserves (f_w) declines.

Table 2 uses estimates just described to obtain predicted values of D_w^* and f_w, corrected from conversion from natural logarithms (see Greene 1997, p. 279), for eight major oil producing states in 1998 and combines these two values to estimate the marginal cost of reserve additions (D_w^* / f_w). Estimates of drilling cost per well (D_w^*) range from \$127,943 in Kansas, where wells tend to be shallow, to \$3,801,410 in Alaska, where the drilling experience is very different as compared to the lower 48 states. Marginal reserve additions from drilling (f_w) range from 7,460 barrels per well in Kansas to 139,638 barrels per well in Alaska. Thus, while drilling a well in Alaska is markedly more expensive than in Kansas, Alaska experiences a greater payoff from these more costly exploration and development efforts. In fact, estimates of the marginal cost of reserve additions, D_w^* / f_w, reflect less variation across states than do estimates of either D_w^* or f_w, ranging from a low of $17.15 per barrel in Kansas to a high of $27.22 in Alaska. Although relatively little variation in D_w^* / f_w would be expected when operators are familiar with costs and payoffs from drilling in alternative locations, values of the marginal cost of reserve additions is not expected to be equal across states. For example, aside from random factors introduced in estimation, variation in D_w^* / f_w between states could be due to differences in oil quality, transportation costs, as well as other factors that can cause wellhead prices of oil to differ across states.

Extraction Costs. Because data on oil extraction costs are weak, $C(q, R)$ could not be econometrically estimated. Instead, this equation was calibrated for each state with a Cobb-Douglas functional form using methods described in Deacon (1993). Cost parameter calibration specifics are described in Appendix A. Results show that the 1998 marginal extraction costs range from a low of $4.89 per barrel in Kansas to a high of $8.81 per barrel in Louisiana. Additionally, the Cobb-Douglas form implies that extraction costs rise without limit as reserves approach zero and that a positive level of reserves will remain at any terminal time T. Thus, boundary conditions used in the simulations reported in section 3 allow production to continue after incentives for further exploration vanish so that the terminal date for the exploration/production program must be set arbitrarily. This fixed program period could be interpreted as the producer's relevant planning horizon.

3. *Simulation Results*

While the model presented can be simulated to obtain responses of exploration and production to changes in various types of taxes in any of 15 oil-producing states, simulations presented below focus on severance tax changes in Wyoming.[5] Despite seemingly large interstate differences in costs and tax structures, changes in severance taxes turn out to have quite similar effects in each of the major oil producing states, so results from one state (Wyoming) are used to represent those found for others.[6] Simulation results reported are based on the assumption that tax changes in one state do not affect the wellhead price of oil seen by operators in other states. This assumption is warranted in view of the fact that oil prices are internationally determined and even the largest producing U.S. state (Texas) accounts for only a small percentage (4.2% from 1970-98) of world output.[7] Moreover, as shown below, tax changes considered appear to lead only to comparatively small changes in output, so interstate effects are unlikely to be important in any case.[8]

Simulations for Wyoming were performed using the instrumental variable estimates of equations (10) and (11), the calibrated production cost function and the tax parameters: $\alpha_p = 0.73$, $\alpha_c = 0.90$, $\alpha_D = 0.72$, $\gamma = 0$ (see Appendix A for details). Tax parameters reflect the effective tax rates described earlier as well as interactions between tax bases at the federal, state, and local levels. Changes in severance tax rates affect only the price tax parameter α_p. The discount rate, r, was set at 4% to reflect the risk-free real rate of long-term borrowing and the future price path was fixed at $23.00 per barrel each year reflecting the real sample mean for all 15 states. Both increasing and decreasing price trajectories also were simulated, but these alternative paths have little or no effect on the comparative results presented below. The initial value of reserves and cumulative wells drilled were fixed to year-end 1998 levels at 550 million barrels and 40,439 wells, respectively. To obtain numerical solutions for the optimal time paths of drilling, production, and reserves, difference equation approximations are derived for the time rates of change in exploratory effort ($\dot{w}$), production ($\dot{q}$), and for the state variable evolution equations (2) and (3). For example, the evolution of reserves, equation (2), is approximated by the difference, $R_{t+1} - R_t = f_t - q_t$. The model is then solved recursively by iterating over the initial values of the control variables, q and w, until transversality conditions are satisfied. Under these base conditions, exploratory effort approaches zero after approximately 40 years, thus the terminal time is set to 40 periods. The solver algorithm in Microsoft Excel was used to generate numerical solutions.

The simulation results are best appreciated using Wyoming's history of oil exploration and production as a backdrop. Figure 1 shows the time paths of real wellhead price, drilling, production, and reserves for Wyoming from 1970-98. In this figure, the vertical axis shows price per bbl (dotted line) in \$1995 × 10, drilling (dashed line) in total wells, production (solid line) in bbls × 10^5, and reserves (bold line) in millions of barrels (MMbbls). The most important observation to be drawn from Figure 1 is that drilling is more sensitive to oil price changes than is production. For example, when oil prices spiked upward in the late 1970s and early 1980s, drilling activity increased, but oil production continued its decline begun in the early 1970s. In fact, oil production declined from the early 1970s to the early 1980s even though real wellhead prices nearly tripled during that time. A possible interpretation here, based on the model presented in Section 2, is that the increased drilling added little to reserves and production from existing wells could not be increased because they already were producing at maximum rates. In any case, Wyoming's experience in this regard paralleled that in other oil producing states (see Moroney 1997 for a discussion of recent trends in the oil industry in Texas).

This insensitivity of production to changes in price suggests that production is likely to be inelastic with respect to changes in severance taxes. As previously indicated, the wellhead price of oil is treated parametrically and severance taxes in Wyoming are levied on the value of production net of public land royalties, so an increase in the severance tax has the same effect as a reduction in the wellhead price (lowers α_p). To examine this issue more closely, the first simulation conducted shows the effects of doubling Wyoming's current effective oil severance tax rate from 5.2% to10.4% for the full 40-year program.[9] Effects of the tax increase, which reduces the net wellhead price received by producers by about $1 per barrel, on the level and timing of drilling, production, and discounted severance tax revenue are presented graphically in Figures 2 and 3 and numerically in the top portion of Table 3. The initial values of the shadow prices λ_1 and λ_2 in the base simulation were $10.55 (decreasing with time but never negative) and $-0.21 (increasing with time but never positive). As shown in Table 3, the tax increase depresses drilling in the early years of the program and tilts it to the future as compared to a base simulation in which no tax changes are contemplated and all other parameter values are the same. Because of the severance tax increase, drilling decreases by 19.4% in the first year of the simulation and 63.8% of the total decrease in numbers of wells drilled occurs in the first 20 years of the program. With a reduction in drilling in the early years, fewer new reserves are identified (51 million barrels less) and, as shown in Figure 3, future production of oil declines as well.

In particular, Table 3 shows that doubling the severance tax rate results in a 2.4% drop in production in the first year of the program and an 11.4% decline in years 31- 40. Through the life of the program, the tax increase results in a decline in production by about 48 million barrels, about 5.7% below the base solution. This difference is roughly equal to the 51 million barrel loss in reserve additions that comes about because of the tax increase. Also, the decline in output reflects a relatively low elasticity of production with respect to tax rate changes. Over the life of the program, this elasticity is approximately 0.06.

The intuition here is that while an increase in the severance tax attenuates drilling activity, the reduction in drilling has a comparatively small effect on reserve levels. Given that over 58,000 wells (oil and gas) have been drilled in Wyoming through 1998, prospects of a significant oil discovery are unlikely and the marginal product of drilling in finding new reserves is lower than in the past. As a consequence, reserve additions also respond inelastically to the severance tax increase. Doubling the tax rate decreases total reserve additions by less than 15% when compared to the no-tax-change solution. Also, the model presented in section 2 indicates that if it is profitable for the firm to produce from given well, then it should produce at maximum capacity. Thus, the tax increase would not be expected to affect production from existing wells at all, except for those at the margin, which become unprofitable to operate and are shut in. The relatively small response of production to tax changes is consistent with views held by petroleum engineers who would argue that output is mainly determined by reserves and geological constraints in bringing oil to the surface (see Figure 1). In fact, the Hubbert (1962) curve proved to be a remarkably accurate long-term forecast of U.S. oil production even though it does not account for changes in oil prices.

The upper section of Table 3 also shows how doubling the state oil severance tax affects severance tax collections. The tax increase results in an increase in the discounted (at 4%) present value of Wyoming severance tax collections from $609 million to $1165 million, an increase of over 91%. The majority (87.6%) of this $556 million increase comes from the first half of the 40-year program and is attributable to the relatively small production loss generated by the tax increase as well as to the fact that future tax collections are discounted to the present. Because severance taxes are deductible in computing federal corporate income tax liabilities, discounted tax payments to the federal government decrease by $60 million or by about 11%. Also, discounted public land royalties decrease by 4.6% ($50 million) because of the decrease in future production.

The tax interactions just described highlight a key feature of the model developed here — oil producers do not face the full effect of an increase in the severance tax rate. As shown, tax base and rate interactions partially offset the direct effect of the severance tax rate increase. This aspect is important to consider when modeling the effects of tax policy changes and distinguishes the current analysis from previous efforts (notably Deacon, DeCanio, Frech, and Johnson 1990 and Deacon 1993). To illustrate this more clearly, simulations were conducted where all tax and royalty parameters, except for state severance tax rates, were fixed at zero. The lower section of Table 3 shows what happens in this case when the effective Wyoming severance tax rate is again doubled. When all tax interactions are ignored, drilling falls by 32.8% and production decreases by

11.2% over the life of the program. These decreases are roughly twice as large as those found in the full tax interaction case examined above. Also, because the severance tax increase now results in a larger production decline, discounted severance taxes increase by 83% as compared to the 91% increase when interactions between taxes are accounted for. The other state models respond in a similar manner. Specifically, the comparative result in California decreases production by approximately 1.9 times more than in the full tax interaction solution. Implications of this outcome partially explain why Deacon, DeCanio, Frech, and Johnson (1990) find larger effects on production from existing wells (11% decrease), when levying a 6% severance tax in California, than found here. Analyzing the severance tax individually appears to overstate the affects on exploration and production by ignoring potential offsets and tax base interactions. These results illustrate the well-known hazards of analyzing effects of taxes individually outside the context of the entire tax structure applied by all levels of government.

In any case, because oil production is relatively inelastic with respect to severance tax changes, public officials in oil producing states have an incentive to increase severance taxes because they risk little lost production and stand to gain a substantial amount of tax revenue. However, the negative impact on employment due to the loss of early period exploration and development efforts would also need to be considered. These impacts, however, may be small because oil-field activity is generally not labor intensive. Yet, the potential employment effects of tax rate changes need to be weighed if states contemplate severance tax changes.

4. Concluding Remarks

The central conclusion of this paper is that oil production is quite inelastic with respect to changes in state severance taxes. In the case of Wyoming, a doubling of the state severance tax is found to reduce production by about 6% over a forty-year period, but will increase severance tax revenue substantially in present value terms, by over ninety percent. Moreover, this general conclusion applies to the other major oil producing states that levy severance taxes. A key question to consider in this regard, therefore, is: If production is relatively inelastic with respect to tax changes, why haven't Wyoming and other major energy producing states raised severance tax rates?

There may be good reasons, or at least arguments, for states to levy higher severance taxes. With respect to demand, the demand for oil is relatively inelastic, at least in the short run. Following the Ramsey Rule and the logic of the inverse elasticity rule, taxing a good with a relatively inelastic demand, because it has few good substitutes, causes a small excess burden, so on efficiency grounds it may be desirable to tax it at a relatively high rate. Boskin and Robinson (1985 p. 13) contend that energy demand is more elastic than previously thought, though they argue it is still inelastic. Regarding supply, energy resources are geographically immobile, indicating that there may be opportunities for the energy states to capture quasi-economic rents earned by energy producing firms in the short run and by owners of mineral rights in the long run. Additionally, because the state taxes on oil tend to be backward shifted and the vast majority of the stockholders of energy firms and royalty holders reside out-of-state, the majority of the severance taxes are exported. In consequence, residents of the energy producing states pay cents on the dollar for public services financed by these taxes (see Gerking and Morgan 1998 for a discussion of this issue).

The reasons for increasing severance tax rates mentioned above suggest that it may be desirable to substitute energy taxes for certain other taxes levied by state and local governments. Alternatively, it may be useful the raise additional revenue from severance taxes to establish or augment mineral trust funds. The earnings from such ‘sinking’ funds can be used to finance government operations long after the minerals have been depleted, and allow governments to substitute earnings from these accounts for other taxes in the future.

Conversely, several arguments have been made against higher taxation of energy. Boskin and Robinson (1985 p. 14) further note, “The simplistic case for relying heavily on energy taxation to collect revenue, on the presumption that rents are thereby being captured and virtually no distortions in production and consumption are occurring, has clearly been overstated.” Additionally, the position of the energy industry has been that low taxation of energy stimulates exploration, development and future production of energy resources. Finally, and more broadly, international security, higher risks associated with exploration, and equity regarding the distribution of income have been used as rationale for lower taxation of the energy sector than other economic sectors.

While most major energy producing states raised severance tax rates during the energy boom of the 1970s, generally, effective tax rates have not increased since then. For example, in Wyoming the effective oil severance tax rate was about 1% in 1970 and has fluctuated around 5% from the early 1980s to date. Similarly, rates from the early 1980s have roughly held to date in Louisiana (11%), Oklahoma (6.6%), Alaska (12%), New Mexico (5%), and in Texas (4.5 to 4%). Consequently, it appears that arguments in favor of low state severance tax rates prevail. This outcome may be partially attributed to a well-organized energy industry lobby that has managed to attain tax concessions (see Interstate Oil and Gas Compact Commission 2001 for specific examples) when energy prices are low, particularly in Wyoming, Oklahoma, and Texas.

Endnotes

[1]Pindyck's (1978) original specification of the extraction cost function is retained here in spite of the logical inconsistencies discussed by Livernois and Uhler (1987), Livernois (1987), and Swierzbinski and Mendelsohn (1989). These authors argue that Pindyck's extraction cost function is defensible when reserves are of uniform quality but in the presence of exploration, reserves must be treated as heterogeneous because the most accessible deposits are added to the reserve base first. They show that aggregation of extraction costs across heterogeneous deposits is not valid except under special circumstances. Another problem with this function is that extraction costs should be a function of γ. The extraction cost function derived from profit-maximization at a point in time subject to a production constraint would have γ as an argument because the reserve base is an input to oil and gas production. These complications are ignored in the analysis below because of severe data constraints on estimating the extraction cost function.

[2] The Energy Information Administration and the American Petroleum Institute report annual production data for 31 states over this period, but data on reserve additions, cumulative drilling, and drilling costs are not available in all years for the 16 smallest producing states. The 15 states included in the panel are Alaska, Alabama, California, Colorado, Kansas, Louisiana, Michigan, Mississippi, Montana, North Dakota, New Mexico, Oklahoma, Texas, Utah, and Wyoming.

[3] Major cost items are for labor, materials, supplies, machinery and tools, water, transportation, fuels, power, and direct overhead for operations such as permitting and preparation, road building, drilling pit construction, erecting and dismantling

derricks/drilling rigs, drilling hole, casing, hauling and disposal of waste materials and site restoration. For additional details, see Joint Association Survey on Drilling Costs, Appendix A (1998).

[4] Corrected (see Greene 1997, p. 279) state-specific intercept terms (and t-statistics) for 8 major producing states are: AK 0.82(1.98), CA 0.17(2.01), KS 0.06(1.06), LA 0.57(2.21), NM 0.19(1.68), OK 0.07(1.94), TX 0.01(1.11), WY 0.29(2.03). Equation (6) was also estimated allowing for both state-specific intercepts and state-specific coefficients for ρ and β. This strategy was unsuccessful as it yielded mostly insignificant estimates of state-specific slope interactions.

[5] Severance taxes are studied here although other types of tax changes also could be analyzed. However, state corporate income taxes affect all incorporated industries within a state so changes of these taxes would expand the analysis beyond the oil industry. Moreover, property taxes on reserves are of less importance currently because they are applied to oil only in two states.

[6] For results of tax changes in other major oil producing states, see Gerking, Kunce, Morgan, and Kerkvliet 2000.

[7] Source of world oil production for 1970-98, www.eia.doe.gov/emeu/international/petroleu.html.

[8] This formulation, in which states are treated independently, would be less appropriate if federal tax changes or multilateral state tax changes were studied. Analyzing federal tax changes would require the addition of a demand curve to the model so that alterations in output would affect the wellhead price. This extension, which is beyond the scope of the

present paper, may be of interest in that it would show how output is shifted between states and over time in response to changing incentives to explore and produce.

[9] While severance tax increases are the focus here, additional simulations in which state severance taxes are eliminated show that tax increases and decreases have roughly symmetric effects.

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Appendix A

Tax Policy Parameters

For most states in most years, γ and α_j *(j=p,c,D)* can be specified by noting whether reserves are subject to a property tax (see text equation (1)) and then evaluating equations (A.1)-(A.4).

$$\gamma = \{(1-\tau_{us})(1-\tau_s)\tau_R\} \qquad \text{(A.1)}$$

$$\alpha_p = \{(1-\tau_{us})(1-\tau_s)(1-\tau_r)(1-\tau_p) + \tau_{us}(1-\tau_r)\delta\} \qquad \text{(A.2)}$$

$$\alpha_C = \{(1-\tau_{us})(1-\tau_S)\} \qquad \text{(A.3)}$$

$$\alpha_D = \{(1-\tau_{us})(1-\tau_S)\eta\} \qquad \text{(A.4)}$$

A derivation of equations (A.1)-(A.4) can be found in Gerking, Morgan, Kunce, and Kerkvliet (2000), Appendix C. In (A.1)-(A.4), τ_{us} denotes the federal corporate income tax rate, τ_s denotes the state corporate income tax rate, τ_R denotes the property tax rate on reserves weighted by the per unit assessed value, τ_r denotes the royalty rate on production from public (state and federal) land, τ_p denotes the production (severance) tax rate, δ denotes the federal percentage depletion allowance weighted by the percentage of production attributable to eligible producers (nonintegrated independents), and η denotes the expensed portion of current and capitalized drilling costs attributable to current period revenues. η is made up of two components: (1) the percentage of current period drilling costs expensed and (2) the estimated present value of cost depletion deductions for the capitalized portion of current and past drilling expenditures. Producers are allowed to expense costs associated with drilling dry holes along with certain intangible costs (e.g., labor and fuel) for completed wells as they are incurred. All direct (tangible) expenditures for completed wells must be capitalized then depleted over the life of the producing well. In the illustration at hand, equations (A.1)-(A.4) can be simplified because Wyoming does not have a state corporate income tax ($\tau_S=0$) and does not levy a property tax against reserves in the ground ($\tau_R=0$).

This formulation captures several aspects of the U.S. tax structure as it applies to the oil industry. (1) Federal royalty payments are deductible in computing state production tax liabilities. (2) Federal royalty payments, state production taxes, state property taxes on reserves, extraction costs, and certain drilling costs (described above) are deductible in computing both state and federal corporate income tax liabilities. (3) State corporate income taxes are deductible against federal corporate income tax liabilities. As noted in text section 2, state tax treatment of the oil industry is not uniform and there are a number of situations in which these equations would have to be modified. Notice that this treatment of taxes in the model highlights the interaction between tax bases and is more detailed than the corresponding treatment given by Moroney (1997) or Deacon, DeCanio, Frech, and Johnson (1990). Also, the entire tax structure is incorporated into the model, rather than simply analyzing one tax at a time as in Deacon (1993).

All tax parameters in equations (A.1)-(A.4) are effective rather than nominal rates. States grant numerous credits and exemptions against taxes levied, so nominal rates generally overstate amounts actually paid. State and local data required for these effective rate calculations are neither available from a central source nor compiled in a common format, so they were obtained directly from tax officials in each state. In developing the *base solution* for Wyoming, royalty rates are computed as the sum of state and federal royalty payments divided by the gross value of production and averaged 9% for oil in the late 1990s. This percentage is higher than for other oil producing states because of the comparatively large share of Wyoming's production on public lands. Production tax rates are computed as total production tax collections divided by the prior year's gross value of production net of public land royalties. In Wyoming, there are both local and state levies against this one-year-lagged net value of production. The sum of the two average effective rates in the late 90's totaled approximately 11.9% (local 6.7% and state 5.2%). At the federal level, data from Statistics of Income (U.S. Department of Treasury, 1997-1998) for the oil and gas sector show that federal corporate taxes paid averaged about 10% of *net operating* income in 1998. Also, the current nominal percentage depletion rate of 15% applied to about 58% of Wyoming oil producers in 1998, thus $\delta = 8.7\%$. Also, the expensed portion of current period drilling costs is approximately 40% for the industry and the present value of depletion deductions for capitalized drilling cost can be approximated by $(q/R)/(r+(q/R))$, assuming that the ratio of production to reserves is constant (Deacon 1993). Wyoming's mean value of q/R was approximately 8% for the sample period 1996-1998, therefore $\eta = 0.40 + (1 - 0.4)*(0.08 / (0.04 + 0.08)) = 0.8$. The base tax policy parameters for Wyoming are $\alpha_p = 0.73$, $\alpha_c = 0.90$, $\alpha_D = 0.72$, $\gamma = 0$.

Estimate of an Instrument for WELLS

An instrument for the natural logarithm of *WELLS* was used as an explanatory variable in estimating both text equations (5) and (6) with *CWELLS* entering equation (6) as the proxy for x. Instrumental variable estimation is appropriate because w is an endogenous variable in the model presented in Section 2. An instrument for w was obtained by predicting the natural logarithm of the number of wells drilled from the one-way fixed-effects regression reported in Table A.1. Time-specific effects tested insignificant at conventional levels and $R^2 = 0.91$. *PRICE* and *CWELLS* were included as explanatory variables because they are exogenous variables in the model. *PRICE2, CWELLS2,* and *PRICE*CWELLS* were included to account for non-linearities expected in light of relationships in the model (see Table 1 for descriptions). All estimated coefficients are significantly different from zero except the interaction term *PRICE*CWELLS*. The marginal effect of *WELLS* with respect to *PRICE* increases at a decreasing rate. The Pearson correlation between the actual values of ln*(WELLS)* and the corresponding predicted values, ln*(PREDWELLS)*, is 0.96.

Table A.1
Construction of Instrument ln*(PREDWELLS)*

Explanatory Variable	***Coefficient*** (t-statistic)
PRICE	0.064 (6.49)
PRICE2	-0.45E-3 (-2.90)
CWELLS	-0.22E-4 (-5.19)
CWELLS2	0.15E-10 (4.17)
*PRICE*CWELLS*	0.18E-7 (1.51)

Extraction Cost Function

Direct operating (lifting) cost for oil by region at depths of 2,000, 4,000, 8,000, and 12,000 feet are available from annual cost index studies published by the DOE/EIA for the period 1970-1998. However, these data are of limited value for two reasons. First, cost estimates are not always disaggregated to the state level and cost estimates for other states may not be representative of all production. Second, through the mid-1980s, price controls on oil and/or gas distorted production incentives, making historical extraction costs difficult to compare with extraction costs in more recent years. As a compromise, following Deacon (1993), values of extraction cost parameters are calibrated for the following Cobb-Douglas function,

$$C(q, R) = \kappa q^{\varepsilon} R^{1-\varepsilon} \ , \tag{A.5}$$

where $\varepsilon = 1/\mu$, μ is the production share of non-reserve inputs, and κ is a constant value that drives the production cost modeled to an average level of *lifting costs* representative of the 1998 DOE/EIA surveyed estimates described above. State-specific estimates for μ are established from the data on operating cost, drilling cost, production, reserve additions, and reserve levels described above (see Kunce, Gerking, and Morgan 2001 for specific calibration methods). Marginal extraction costs per barrel using 1998 data for 7 major producing states are: CA \$6.12, KS \$4.89, LA \$8.81, NM \$6.27, OK \$6.89, TX \$6.71, and WY \$6.43. The DOE/EIA does not provide cost estimates for Alaska. The 1998 calibrated oil production cost parameters for Wyoming are $\varepsilon = 2.93$ and $\kappa = 141$.

Table 1
Variable Definitions, Data Sources, and Sample Means
(Excludes Federal OCS activity.)

Variable	***Definition***	***Source***	***Mean***
TRCOST	Total drilling cost in millions of 1995 dollars, by state and year.	American Petroleum Institute, *Joint Association Survey on Drilling Costs.* Annual.	427.6
ADDED RESERVES	Oil reserve extensions, new field discoveries and new reservoir discoveries in old fields, by state and year in millions of barrels.	US Energy Information Administration, *U.S. Crude Oil, Natural Gas and Gas Liquids Reserves Annual Report.* Annual	42.0
WELLS	Oil wells drilled in a state by year.	American Petroleum Institute, *Joint Association Survey on Drilling Costs.* Annual.	943
CWELLS	Cumulative total wells drilled in a state beginning in 1859.	American Petroleum Institute, *Petroleum Facts & Figures.* 1971 Ed.	1.07E+5
PRICE	Average well head oil price, by state and year, in 1995 dollars per barrel.	American Petroleum Institute, *Basic Petroleum Data Book.* Annual.	22.80
PRICE2	Average real price per barrel squared.	- -	656.3
CWELLS2	Cumulative oil wells squared.	- -	4.3E+10
*PRICE * CWELLS*	Interaction of real price and cumulative wells.	- -	2.5E+6

Table 2
Pre-Tax Marginal Drilling Cost, Marginal Reserve Additions,
and Pre-Tax Marginal Cost of Reserve Additions for 8 Major Producing States

State	D_w^* **(in \$)**	f_w **(in bbls)**[a]	D_w^* / f_w [a]
Alaska	3,801,410	139,638	27.22
California	274,675	11,464	23.96
Kansas	127,943	7,460	17.15
Louisiana	1,218,758	64,862	18.79
New Mexico	485,698	22,148	21.93
Oklahoma	345,706	15,223	22.71
Texas	342,266	13,144	26.04
Wyoming	593,162	34,627	17.13

[a] Assumes wells drilled at the actual 1998 count. State-specific cumulative wells total is set to actual 1998 values in all calculations.

Table 3
Timing of Drilling, Production,
and Discounted Severance Tax Revenue

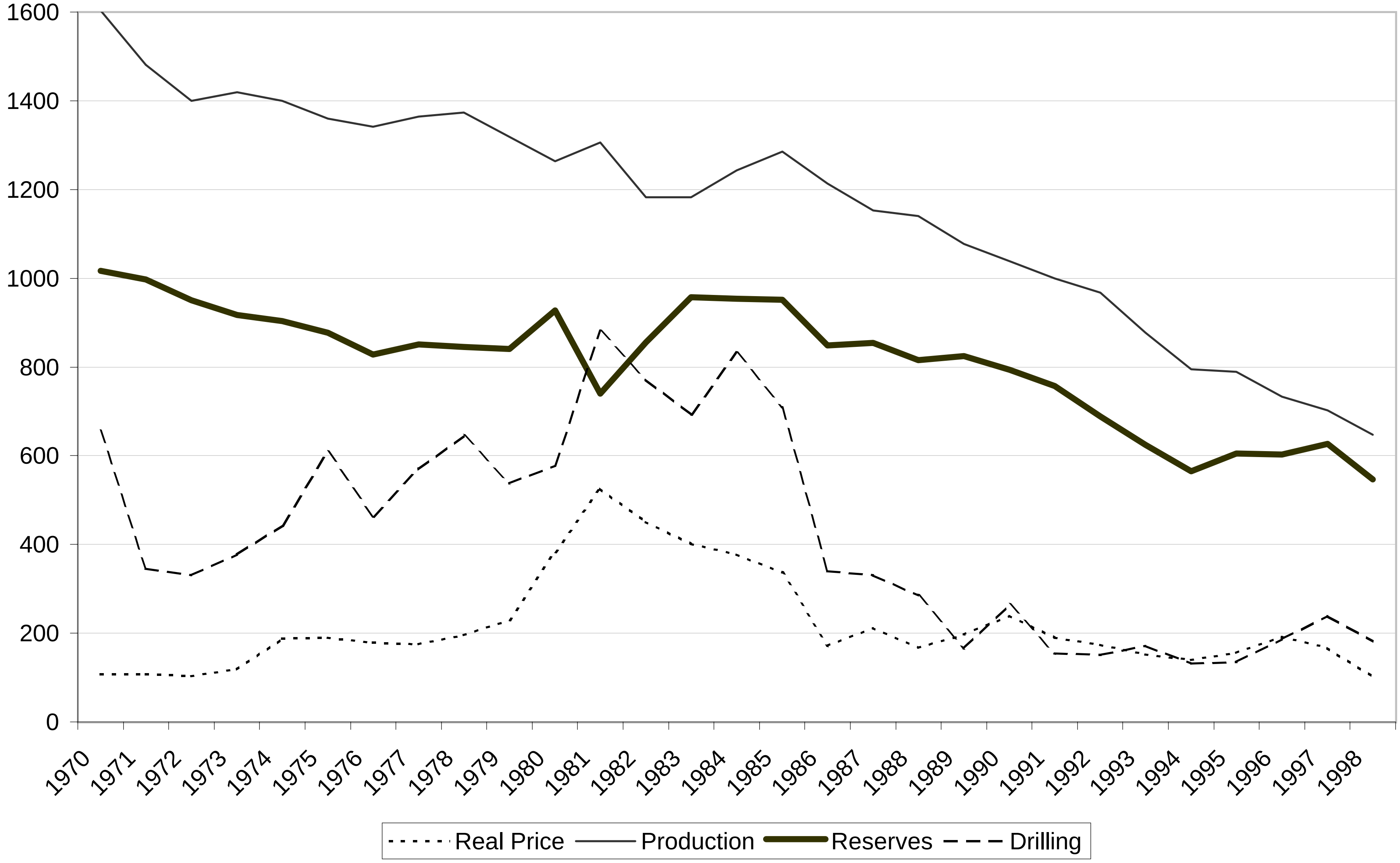
Full Tax Interaction Model

	Program Years:					
	Year 1	***Years 1-10***	***Years 11-20***	***Years 21-30***	***Years 31-40***	***Total***
Drilling (Base Solution, in wells)	211	2073	1958	1623	620	6274
Drilling (Double Tax)	170	1675	1586	1310	495	5066
Change from Base	-19.4 %	-19.2 %	-19.0 %	-19.2 %	-20.1 %	-19.3 %
Production (Base, in MMbbls)	57.7	399.0	198.8	135.9	100.6	834.3
Production (Double Tax)	56.3	387.5	186.9	123.1	89.1	786.6
Change from Base	-2.4 %	-2.9 %	-6.0 %	-9.4 %	-11.4 %	-5.7 %
Severance Tax Revenue (Base, $MM)	66.6	395.6	127.3	56.8	28.9	608.6
Severance Tax Revenue (Double Tax)	130.2	769.7	240.8	103.3	51.4	1165.2
Change from Base	95.5 %	94.6 %	89.2 %	81.9 %	77.8 %	91.5 %

No Tax Interaction Model

	Program Years:					
	Year 1	***Years 1-10***	***Years 11-20***	***Years 21-30***	***Years 31-40***	***Total***
Drilling (Base Solution, in wells)	283	2771	2605	2164	823	8363
Drilling (Double Tax)	189	1860	1760	1456	548	5624
Change from Base	-33.2 %	-32.9 %	-32.4 %	-32.7 %	-33.4 %	-32.8 %
Production (Base, in MMbbls)	59.6	417.2	218.4	156.9	118.5	911.0
Production (Double Tax)	57.0	393.0	192.6	129.2	94.5	809.3
Change from Base	-4.4 %	-5.8 %	-11.8 %	-17.7 %	-20.3 %	-11.2 %
Severance Tax Revenue (Base, $MM)	75.6	452.6	152.6	71.7	37.4	714.3
Severance Tax Revenue (Double Tax)	144.7	857.1	271.9	119.0	59.8	1307.8
Change from Base	91.4 %	89.4 %	78.2 %	65.9 %	59.9 %	83.1 %

Figure 1. Wyoming Oil, 1970-98



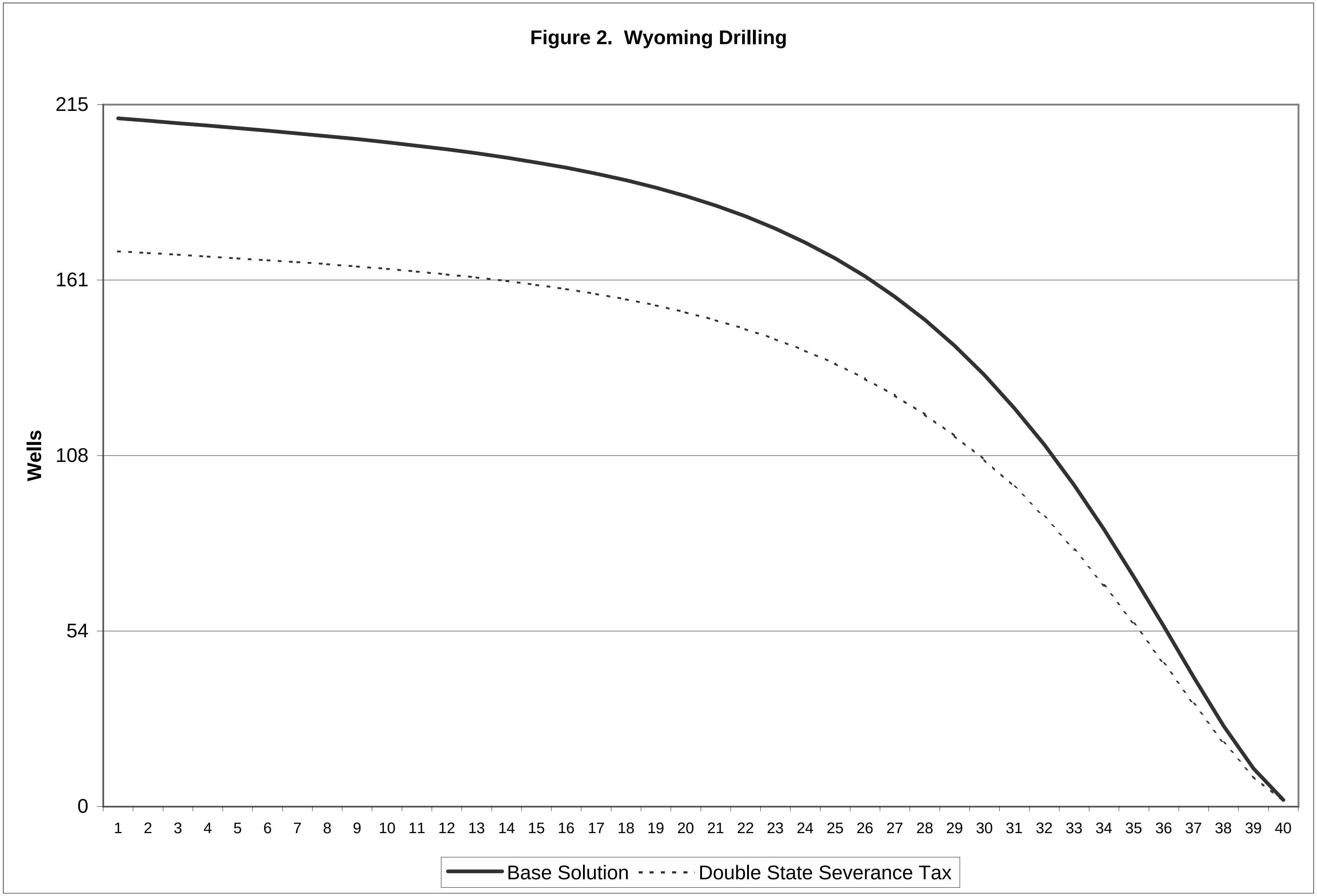


Figure 2. Wyoming Drilling
Wells
215
161
108
54
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40
Base Solution
Double State Severance Tax

Figure 3. Wyoming Production